What is claimed is:

1. A method of estimating physical parameters of porous rocks of a subterranean formation containing a compressible reservoir fluid comprising the steps of:

(a) injecting an injection fluid into the subterranean formation at an injection pressure exceeding the subterranean formation fracture pressure;

(b) shutting in the subterranean formation;

(c) gathering pressure measurement data over time from the subterranean formation during shut-in;

(d) transforming the pressure measurement data into corresponding adjusted pseudopressure data to minimize error associated with pressure-dependent reservoir fluid properties; and

(e) determining the physical parameters of the subterranean formation from the adjusted pseudopressure data.

2. The method of claim 1 wherein a plot of the adjusted pseudopressure data over time is a straight line with a slope m_M and an intercept b_M, wherein m_M is a function of permeability k and b_M is a function of fracture-face resistance R_0.

3. The method of claim 2 wherein the adjusted pseudopressure data used in the transforming step are derived using following equation:

$$(p_a)_n = \frac{\bar{\mu}_g \bar{c}_t}{\bar{p}} \int_0^{(p_w)_n} \frac{p\,dp}{\mu_g c_t}, \text{ wherein}$$

$\bar{\mu}$	= average viscosity, m/Lt, cp
μ_g	= gas viscosity, m/Lt, cp
p	= pressure, m/Lt^2, psi
$\bar{p}$	= average pressure, m/Lt^2, psi
p_a	= adjusted pseudopressure variable, m/Lt^2, psi
p_w	= wellbore pressure, m/Lt^2, psi
$p_{L_f D}$	= dimensionless pressure in a hydraulically fractured well, dimensionless
c_t	= total compressibility, Lt^2/m, psi^{-1}
$\bar{c}_t$	= average total compressibility, Lt^2/m, psi^{-1}

4. The method of claim 3 wherein the straight line is defined by the equation:

$(y_a)_n = m_M (x_a)_n + b_M$, where

$$(y_a)_n \equiv \frac{(p_a)_n - p_{ar}}{(d_a)_n \sqrt{t_n} \sqrt{t_{ne}}},$$

$$(d_a)_j \equiv \frac{(\mu_g)_j}{\bar{\mu}_g} \left[\frac{[p_a(p)]_{j-1} - [p_a(p)]_j}{t_j - t_{j-1}} \right], \text{ and}$$

$$(x_a)_n \equiv \left[\begin{array}{l} c_{a1} \left[\begin{array}{l} \dfrac{(d_a)_{ne+2}}{(d_a)_n} \left(\dfrac{t_n - t_{ne+1}}{t_n t_{ne}} \right)^{1/2} \\ + \displaystyle\sum_{j=ne+3}^{n} \dfrac{[(d_a)_j - (d_a)_{j-1}]}{(d_a)_n} \left(\dfrac{t_n - t_{j-1}}{t_n t_{ne}} \right)^{1/2} \end{array} \right] \\ + \dfrac{c_{a2}}{(d_a)_n t_{ne}^{3/2}} \left[1 - \left(1 - \dfrac{t_{ne+1}}{t_n} \right)^{1/2} \right] \end{array} \right]$$

wherein

c_{a1}	= a first before-closure pressure-transient analysis adjusted variable, $m/Lt^{3/2}$, $psi^{1/2} \cdot cp^{1/2}$
c_{a2}	= a second before-closure pressure-transient analysis adjusted variable, $m^2/L^2t^{7/2}$, $psi^{3/2} \cdot cp^{1/2}$
d_a	= before-closure pressure-transient analysis adjusted variable, m/Lt^3, psi/hr
Δp_a	= adjusted pressure variable difference, m/Lt^2, psi
p_{ar}	= adjusted reservoir pressure variable, m/Lt^2, psi
p_{aw}	= wellbore adjusted pressure variable, m/Lt^2, psi
t_n	= time at timestep n, t, hr
t_{ne}	= time at the end of an injection, t, hr
$(x_a)_n$	= before-closure pressure-transient analysis adjusted variable, dimensionless
$(y_a)_n$	= before-closure pressure-transient analysis adjusted variable, dimensionless

5. The method of claim 4 wherein the first and second before-closure pressure-transient analysis variables are defined as:

$$c_{a1} \equiv \sqrt{\frac{\bar{\mu}_g}{\phi \bar{c}_t}} \text{ ; and}$$

$$c_{a2} \equiv \frac{5.615}{24} S_f w_L \frac{\bar{B}_g}{(B_g)_{ne}} \sqrt{\frac{\bar{\mu}_g}{\phi \bar{c}_t}};$$

wherein

ϕ	= porosity, dimensionless
B_g	= gas formation volume factor, dimensionless, bbl/Mscf
$\bar{B}_g$	= average gas formation volume factor, dimensionless, bbl/Mscf
S_f	= fracture stiffness, m/L^{2}t^2, psi/ft
w_L	= fracture lost width, L, ft

6. The method of claim 5 wherein the transforming step is iterated with a value of n varying from ne+1 to a maximum value n_{max} and for each couple of coordinates $\{(y_a)_n, (x_a)_n\}$ plot the graph $(y_a)_n$ versus $(x_a)_n$ to determine the slope m_M and the intercept b_M,

wherein

ne	= number of measurements that corresponds to the end of an injection
n_{max}	= corresponds to the data point recorded at fracture closure or the last recorded data point before induced fracture closure

7. The method of claim 6 wherein the permeability k and the fracture-face R_0 are determined by the following equations:

$$k = \left[\frac{(141.2)(2)(0.02878)(24)}{5.615} \frac{1}{r_p S_f m_M} \right]^2$$

$$R_0 = \frac{5.615}{141.2\pi(24)} r_p S_f t_{ne} b_M$$

8. The method of claim 6 wherein the permeability k and the fracture-face R_0 are determined by the following equations:

$$\omega k = \left[\frac{(141.2)(2)(0.02878)(24)}{5.615} \frac{1}{r_p S_f m_M} \right]^2$$

$$R_0 = \frac{5.615}{141.2\pi(24)} r_p S_f t_{ne} b_M$$

wherein

ω	= natural fracture storativity ratio, dimensionless.

9. The method of claim 1 wherein the injection fluid is a liquid, a gas or a combination thereof.

10. The method of claim 9 wherein the injection fluid contains desirable additives for compatibility with the subterranean formation.

11. The method of claim 1 wherein the reservoir fluid is a liquid, a gas or a combination thereof.

12. A method of estimating physical parameters of porous rocks of a subterranean formation containing a compressible reservoir fluid comprising the steps of:

(a) injecting an injection fluid into the subterranean formation at an injection pressure exceeding the subterranean formation fracture pressure;

(b) shutting in the subterranean formation;

(c) gathering pressure measurement data over time from the subterranean formation during shut-in;

(d) transforming the pressure measurement data into corresponding adjusted pseudopressure data and time into adjusted pseudotime data to minimize error associated with pressure-dependent reservoir fluid properties; and

(e) determining the physical parameters of the subterranean formation from the adjusted pseudopressure and adjusted pseudotime data.

13. The method of claim 12 wherein a plot of the adjusted pseudopressure data over time is a straight line with a slope m_M and an intercept b_M, wherein m_M is a function of permeability k and b_M is a function of fracture-face resistance R_0.

14. The method of claim 13 wherein the adjusted pseudotime and adjusted pseudopressure data used in the transforming step are respectively determined by the following equations:

$$(t_a)_n = (\mu_g c_t)_0 \int_0^{(\Delta t)_n} \frac{d\Delta t}{(\mu_g c_t)_w}, \text{ and}$$

$$(p_a)_n = \frac{\bar{\mu}_g \bar{c}_t}{\bar{p}} \int_0^{(p_w)_n} \frac{p dp}{\mu_g c_t}, \text{ wherein}$$

$\bar{\mu}$	=	average viscosity, m/Lt, cp
μ_g	=	gas viscosity, m/Lt, cp
p	=	pressure, m/Lt^2, psi
$\bar{p}$	=	average pressure, m/Lt^2, psi
p_a	=	adjusted pseudopressure variable, m/Lt^2, psi
p_w	=	wellbore pressure, m/Lt^2, psi
$p_{L_f D}$	=	dimensionless pressure in a hydraulically fractured well, dimensionless
c_t	=	total compressibility, Lt^2/m, psi^{-1}

$\bar{c}_t$ = average total compressibility, Lt^2/m, psi^{-1}.

15. The method of claim 14 wherein the straight line is defined by the equation:

$(y_{ap})_n = b_M + m_M (x_{ap})_n$, where

$$(y_{ap})_n \equiv \frac{(p_a)_n - p_{ar}}{(d_{ap})_n \sqrt{t_n}\sqrt{t_{ne}}},$$

$$(d_{ap})_j \equiv \frac{\bar{c}_t}{(c_t)_j}\left[\frac{[p_a(p)]_{j-1} - [p_a(p)]_j}{(t_a)_j - (t_a)_{j-1}}\right], \text{ and}$$

$$(x_{ap})_n \equiv \left[\begin{array}{l} c_{ap1}\left[\begin{array}{l} \dfrac{(d_{ap})_{ne+2}}{(d_{ap})_n}\left[\dfrac{(t_a)_n - (t_a)_{ne+1}}{t_n t_{ne}}\right]^{1/2} \\ + \displaystyle\sum_{j=ne+3}^{n} \dfrac{[(d_{ap})_j - (d_{ap})_{j-1}]}{(d_{ap})_n}\left(\dfrac{(t_a)_n - (t_a)_{j-1}}{t_n t_{ne}}\right)^{1/2} \end{array}\right] \\ + \dfrac{c_{ap2}(t_a)_n^{1/2}}{(d_{ap})_n t_n^{1/2} t_{ne}^{3/2}}\left[1 - \left(1 - \dfrac{(t_a)_{ne+1}}{(t_a)_n}\right)^{1/2}\right] \end{array}\right]$$

wherein

$c_{ap1}=c_{a1}$ = a first before-closure pressure-transient analysis adjusted variable, $m/Lt^{3/2}$, $psi^{1/2}\cdot cp^{1/2}$

$c_{ap2}=c_{a2}$ = a second before-closure pressure-transient analysis adjusted variable, $m^2/L^2t^{7/2}$, $psi^{3/2}\cdot cp^{1/2}$

d_{ap} = before-closure pressure-transient analysis adjusted variable, m/Lt^3, psi/hr, with adjusted pseudotime variable

Δp_a = adjusted pressure variable difference, m/Lt^2, psi

p_{ar} = adjusted reservoir variable pressure, m/Lt^2, psi

p_{aw} = wellbore adjusted pressure variable, m/Lt^2, psi

t_n = time at timestep n, t, hr

t_{ne} = time at the end of an injection, t, hr

$(t_a)_n$ = adjusted time at timestep n, t, hr

$(x_{ap})_n$ = before-closure pressure-transient analysis adjusted variable, dimensionless

$(y_{ap})_n$ = before-closure pressure-transient analysis adjusted variable, dimensionless.

16. The method of claim 15 wherein the first and second before-closure pressure-transient analysis variables are defined as:

$$c_{a1} \equiv \sqrt{\frac{\bar{\mu}_g}{\phi \bar{c}_t}}$$; and

$$c_{a2} \equiv \frac{5.615}{24} S_f w_L \frac{\bar{B}_g}{(B_g)_{ne}} \sqrt{\frac{\bar{\mu}_g}{\phi \bar{c}_t}};$$

wherein

ϕ	= porosity, dimensionless
B_g	= gas formation volume factor, dimensionless, bbl/Mscf
$\bar{B}_g$	= average gas formation volume factor, dimensionless, bbl/Mscf
S_f	= fracture stiffness, m/L^{2}t^2, psi/ft
w_L	= fracture lost width, L, ft.

17. The method of claim 16 wherein the transforming step is iterated with a value of n varying from ne+1 to a maximum value n_{max} and for each couple of coordinates $\{(y_{ap})_n, (x_{ap})_n\}$ plot the graph $(y_{ap})_n$ versus $(x_{ap})_n$ to determine the slope m_M and the intercept b_M,

wherein

ne	= number of measurements that corresponds to the end of an injection
n_{max}	= corresponds to the data point recorded at fracture closure or the last recorded data point before induced fracture closure.

18. The method of claim 17 wherein the permeability k and the fracture-face R_0 are determined by the following equations:

$$k = \left[\frac{(141.2)(2)(0.02878)(24)}{5.615} \frac{1}{r_p S_f m_M} \right]^2$$

$$R_0 = \frac{5.615}{141.2\pi(24)} r_p S_f t_{ne} b_M .$$

19. The method of claim 17 wherein the permeability k and the fracture-face R_0 are determined by the following equations:

$$\omega k = \left[\frac{(141.2)(2)(0.02878)(24)}{5.615} \frac{1}{r_p S_f m_M} \right]^2$$

$$R_0 = \frac{5.615}{141.2\pi(24)} r_p S_f t_{ne} b_M$$

wherein

ω = natural fracture storativity ratio, dimensionless.

20. The method of claim 12 wherein the injection fluid is a liquid, a gas or a combination thereof.

21. The method of claim 20 wherein the injection fluid contains desirable additives for compatibility with the subterranean formation.

22. The method of claim 12 wherein the reservoir fluid is a liquid, a gas or a combination thereof.

23. A method of estimating permeability k of porous rocks of a subterranean formation containing a compressible reservoir fluid comprising the steps of:

(a) injecting an injection fluid into the subterranean formation at an injection pressure exceeding the subterranean formation fracture pressure;

(b) shutting in the subterranean formation;

(c) gathering pressure measurement data over time from the subterranean formation during shut-in;

(d) transforming the pressure measurement data into corresponding adjusted pseudopressure data to minimize error associated with pressure-dependent reservoir fluid properties; and

(e) determining the permeability k of the subterranean formation from the adjusted pseudopressure data.

24. The method of claim 23 wherein a plot of the adjusted pseudopressure data over time is a straight line with a slope m_M which is a function of permeability k.

25. The method of claim 24 wherein the adjusted pseudopressure data used in the transforming step are derived using the following equation:

$$(p_a)_n = \frac{\bar{\mu}_g \bar{c}_t}{\bar{p}} \int_0^{(p_w)_n} \frac{p dp}{\mu_g c_t}, \text{ wherein}$$

$\bar{\mu}$	= average viscosity, m/Lt, cp
μ_g	= gas viscosity, m/Lt, cp
p	= pressure, m/Lt^2, psi
$\bar{p}$	= average pressure, m/Lt^2, psi
p_a	= adjusted pseudopressure variable, m/Lt^2, psi
p_w	= wellbore pressure, m/Lt^2, psi
p_{L_fD}	= dimensionless pressure in a hydraulically fractured well, dimensionless
c_t	= total compressibility, Lt^2/m, psi^{-1}
$\bar{c}_t$	= average total compressibility, Lt^2/m, psi^{-1}.

26. The method of claim 25 wherein the straight line is defined by the equation:

$(y_a)_n = m_M (x_a)_n + b_M$, where

$$(y_a)_n \equiv \frac{(p_a)_n - p_{ar}}{(d_a)_n \sqrt{t_n}\sqrt{t_{ne}}},$$

$$(d_a)_j \equiv \frac{(\mu_g)_j}{\bar{\mu}_g}\left[\frac{[p_a(p)]_{j-1} - [p_a(p)]_j}{t_j - t_{j-1}}\right], \text{ and}$$

$$(x_a)_n \equiv \left[\begin{array}{l} c_{a1}\left[\begin{array}{l} \dfrac{(d_a)_{ne+2}}{(d_a)_n}\left(\dfrac{t_n - t_{ne+1}}{t_n t_{ne}}\right)^{1/2} \\ + \displaystyle\sum_{j=ne+3}^{n} \dfrac{[(d_a)_j - (d_a)_{j-1}]}{(d_a)_n}\left(\dfrac{t_n - t_{j-1}}{t_n t_{ne}}\right)^{1/2} \end{array}\right] \\ + \dfrac{c_{a2}}{(d_a)_n t_{ne}^{3/2}}\left[1 - \left(1 - \dfrac{t_{ne+1}}{t_n}\right)^{1/2}\right] \end{array}\right]$$

wherein

c_{a1}	= a first before-closure pressure-transient analysis adjusted variable, $m/Lt^{3/2}$, $psi^{1/2} \cdot cp^{1/2}$
c_{a2}	= a second before-closure pressure-transient analysis adjusted variable, $m^2/L^2t^{7/2}$, $psi^{3/2} \cdot cp^{1/2}$
d_a	= before-closure pressure-transient analysis adjusted variable, m/Lt^3, psi/hr
Δp_a	= adjusted pressure variable difference, m/Lt^2, psi
p_{ar}	= adjusted reservoir pressure variable, m/Lt^2, psi
p_{aw}	= wellbore adjusted pressure variable, m/Lt^2, psi
t_n	= time at timestep n, t, hr
t_{ne}	= time at the end of an injection, t, hr
$(x_a)_n$	= before-closure pressure-transient analysis adjusted variable, dimensionless
$(y_a)_n$	= before-closure pressure-transient analysis adjusted variable, dimensionless.

27. The method of claim 26 wherein the first and second before-closure pressure-transient analysis variables are defined as:

$$c_{a1} \equiv \sqrt{\frac{\bar{\mu}_g}{\phi \bar{c}_t}} \text{ ; and}$$

$$c_{a2} \equiv \frac{5.615}{24} S_f w_L \frac{\bar{B}_g}{(B_g)_{ne}} \sqrt{\frac{\bar{\mu}_g}{\phi \bar{c}_t}};$$

wherein

ϕ	= porosity, dimensionless

B_g	= gas formation volume factor, dimensionless, bbl/Mscf
$\bar{B}_g$	= average gas formation volume factor, dimensionless, bbl/Mscf
S_f	= fracture stiffness, m/L^{2}t^2, psi/ft
w_L	= fracture lost width, L, ft.

28. The method of claim 27 wherein the transforming step is iterated with a value of n varying from ne+1 to a maximum value n_{max} and for each couple of coordinates $\{(y_a)_n, (x_a)_n\}$ plot the graph $(y_a)_n$ versus $(x_a)_n$ to determine the slope m_M,

wherein

ne	= number of measurements that corresponds to the end of an injection
n_{max}	= corresponds to the data point recorded at fracture closure or the last recorded data point before induced fracture closure.

29. The method of claim 28 wherein the permeability k is determined by the following equation:

$$k = \left[\frac{(141.2)(2)(0.02878)(24)}{5.615} \frac{1}{r_p S_f m_M} \right]^2 .$$

30. The method of claim 28 wherein the permeability k is determined by the following equation:

$$\omega k = \left[\frac{(141.2)(2)(0.02878)(24)}{5.615} \frac{1}{r_p S_f m_M} \right]^2 ;$$

wherein

ω	= natural fracture storativity ratio, dimensionless.

31. The method of claim 23 wherein the injection fluid is a liquid, a gas or a combination thereof

32. The method of claim 31 wherein the injection fluid contains desirable additives for compatibility with the subterranean formation.

33. The method of claim 23 wherein the reservoir fluid is a liquid, a gas or a combination thereof.

34. A method of estimating permeability k of porous rocks of a subterranean formation containing a compressible reservoir fluid comprising the steps of:

(a) injecting an injection fluid into the subterranean formation at an injection pressure exceeding the subterranean formation fracture pressure;

(b) shutting in the subterranean formation;

(c) gathering pressure measurement data over time from the subterranean formation during shut-in;

(d) transforming the pressure measurement data into corresponding adjusted pseudopressure data and time into adjusted pseudotime data to minimize error associated with pressure-dependent reservoir fluid properties; and

(e) determining the permeability k of the subterranean formation from the adjusted pseudopressure and adjusted pseudotime data.

35. The method of claim 34 wherein a plot of the adjusted pseudopressure data over adjusted pseudotime data is a straight line with a slope m_M which is a function of permeability k.

36. The method of claim 35 wherein the adjusted pseudotime and adjusted pseudopressure data used in the transforming step are respectively determined by the following equations:

$$(t_a)_n = (\mu_g c_t)_0 \int_0^{(\Delta t)_n} \frac{d\Delta t}{(\mu_g c_t)_w}\text{; and}$$

$$(p_a)_n = \frac{\bar{\mu}_g \bar{c}_t}{\bar{p}} \int_0^{(p_w)_n} \frac{p dp}{\mu_g c_t}\text{, wherein}$$

$\bar{\mu}$ = average viscosity, m/Lt, cp
μ_g = gas viscosity, m/Lt, cp
p = pressure, m/Lt^2, psi
$\bar{p}$ = average pressure, m/Lt^2, psi
p_a = adjusted pseudopressure variable, m/Lt^2, psi
p_w = wellbore pressure, m/Lt^2, psi
$p_{L_f D}$ = dimensionless pressure in a hydraulically fractured well, dimensionless
c_t = total compressibility, Lt^2/m, psi^{-1}
$\bar{c}_t$ = average total compressibility, Lt^2/m, psi^{-1}.

37. The method of claim 36 wherein the straight line is defined by the equation:

$(y_{ap})_n = b_M + m_M (x_{ap})_n$, where

$$(y_{ap})_n \equiv \frac{(p_a)_n - p_{ar}}{(d_{ap})_n \sqrt{t_n}\sqrt{t_{ne}}},$$

$$(d_{ap})_j \equiv \frac{\bar{c}_t}{(c_t)_j}\left[\frac{[p_a(p)]_{j-1} - [p_a(p)]_j}{(t_a)_j - (t_a)_{j-1}}\right], \text{ and}$$

$$(x_{ap})_n \equiv \left[c_{ap1}\left[\begin{array}{l} \dfrac{(d_{ap})_{ne+2}}{(d_{ap})_n}\left[\dfrac{(t_a)_n - (t_a)_{ne+1}}{t_n t_{ne}}\right]^{1/2} \\ + \displaystyle\sum_{j=ne+3}^{n} \frac{[(d_{ap})_j - (d_{ap})_{j-1}]}{(d_{ap})_n}\left(\frac{(t_a)_n - (t_a)_{j-1}}{t_n t_{ne}}\right)^{1/2} \end{array} \right] + \frac{c_{ap2}(t_a)_n^{1/2}}{(d_{ap})_n t_n^{1/2} t_{ne}^{3/2}}\left[1 - \left(1 - \frac{(t_a)_{ne+1}}{(t_a)_n}\right)^{1/2}\right] \right]$$

wherein

$c_{ap1} = c_{a1}$	= a first before-closure pressure-transient analysis adjusted variable, $m/Lt^{3/2}$, $psi^{1/2} \cdot cp^{1/2}$
$c_{ap2} = c_{a2}$	= a second before-closure pressure-transient analysis adjusted variable, $m^2/L^2t^{7/2}$, $psi^{3/2} \cdot cp^{1/2}$
d_{ap}	= before-closure pressure-transient analysis adjusted variable, m/Lt^3, psi/hr, with adjusted pseudotime variable
Δp_a	= adjusted pressure variable difference, m/Lt^2, psi
p_{ar}	= adjusted reservoir pressure variable, m/Lt^2, psi
p_{aw}	= wellbore adjusted pressure variable, m/Lt^2, psi
t_n	= time at timestep n, t, hr
t_{ne}	= time at the end of an injection, t, hr
$(t_a)_n$	= adjusted time at timestep n, t, hr
$(x_{ap})_n$	= before-closure pressure-transient analysis adjusted variable, dimensionless
$(y_{ap})_n$	= before-closure pressure-transient analysis adjusted variable, dimensionless.

38. The method of claim 37 wherein the first and second before-closure pressure-transient analysis variables are defined as:

$c_{a1} \equiv \sqrt{\dfrac{\bar{\mu}_g}{\phi \bar{c}_t}}$; and

$$c_{a2} \equiv \frac{5.615}{24} S_f w_L \frac{\bar{B}_g}{(B_g)_{ne}} \sqrt{\frac{\bar{\mu}_g}{\phi \bar{c}_t}};$$

wherein

ϕ	= porosity, dimensionless
B_g	= gas formation volume factor, dimensionless, bbl/Mscf
$\bar{B}_g$	= average gas formation volume factor, dimensionless, bbl/Mscf
S_f	= fracture stiffness, m/L^2t^2, psi/ft
w_L	= fracture lost width, L, ft.

39. The method of claim 38 wherein the transforming step is iterated with a value of n varying from $ne+1$ to a maximum value n_{max} and for each couple of coordinates $\{(y_{ap})_n, (x_{ap})_n\}$ plot the graph $(y_{ap})_n$ versus $(x_{ap})_n$ to determine the slope m_M,

wherein

ne	= number of measurements that corresponds to the end of an injection
n_{max}	= corresponds to the data point recorded at fracture closure or the last recorded data point before induced fracture closure.

40. The method of claim 39 wherein the permeability k is determined by:

$$k = \left[\frac{(141.2)(2)(0.02878)(24)}{5.615} \frac{1}{r_p S_f m_M} \right]^2 .$$

41. The method of claim 39 wherein the permeability k is determined by:

$$\omega k = \left[\frac{(141.2)(2)(0.02878)(24)}{5.615} \frac{1}{r_p S_f m_M} \right]^2 .$$

wherein

ω	= natural fracture storativity ratio, dimensionless.

42. The method of claim 34 wherein the injection fluid is a liquid, a gas or a combination thereof.

43. The method of claim 42 wherein the injection fluid contains desirable additives for compatibility with the subterranean formation

44. The method of claim 34 wherein the reservoir fluid is a liquid, a gas or a combination thereof.

45. A method of estimating fracture-face resistance R_0 of porous rocks of a subterranean formation containing a compressible reservoir fluid comprising the steps of:

(a) injecting an injection fluid into the subterranean formation at an injection pressure exceeding the subterranean formation fracture pressure;

(b) shutting in the subterranean formation;

(c) gathering pressure measurement data over time from the subterranean formation during shut-in;

(d) transforming the pressure measurement data into corresponding adjusted pseudopressure data to minimize error associated with pressure-dependent reservoir fluid properties; and

(e) determining the fracture-face resistance R_0 of the subterranean formation from the adjusted pseudopressure data.

46. The method of claim 45 wherein a plot of the adjusted pseudopressure data over time is a straight line with an intercept b_M a function of fracture-face resistance R_0.

47. The method of claim 46 wherein the adjusted pseudopressure data used in the transforming step are derived from the following equation:

$(p_a)_n = \dfrac{\bar{\mu}_g \bar{c}_t}{\bar{p}} \displaystyle\int_0^{(p_w)_n} \dfrac{p dp}{\mu_g c_t}$, wherein

$\bar{\mu}$	= average viscosity, m/Lt, cp
μ_g	= gas viscosity, m/Lt, cp
p	= pressure, m/Lt^2, psi
$\bar{p}$	= average pressure, m/Lt^2, psi
p_a	= adjusted pseudopressure variable, m/Lt^2, psi
p_w	= wellbore pressure, m/Lt^2, psi
$p_{L_f D}$	= dimensionless pressure in a hydraulically fractured well, dimensionless
c_t	= total compressibility, Lt^2/m, psi^{-1}
$\bar{c}_t$	= average total compressibility, Lt^2/m, psi^{-1}.

48. The method of claim 47 wherein the straight line is defined by the equation:

$(y_a)_n = m_M (x_a)_n + b_M$, where

$$(y_a)_n \equiv \frac{(p_a)_n - p_{ar}}{(d_a)_n \sqrt{t_n}\sqrt{t_{ne}}},$$

$$(d_a)_j \equiv \frac{(\mu_g)_j}{\bar{\mu}_g}\left[\frac{[p_a(p)]_{j-1} - [p_a(p)]_j}{t_j - t_{j-1}}\right], \text{ and}$$

$$(x_a)_n \equiv \left[\begin{array}{l} c_{a1}\left[\begin{array}{l} \frac{(d_a)_{ne+2}}{(d_a)_n}\left(\frac{t_n - t_{ne+1}}{t_n t_{ne}}\right)^{1/2} \\ + \sum_{j=ne+3}^{n} \frac{[(d_a)_j - (d_a)_{j-1}]}{(d_a)_n}\left(\frac{t_n - t_{j-1}}{t_n t_{ne}}\right)^{1/2} \end{array}\right] \\ + \frac{c_{a2}}{(d_a)_n t_{ne}^{3/2}}\left[1 - \left(1 - \frac{t_{ne+1}}{t_n}\right)^{1/2}\right] \end{array}\right]$$

wherein

c_{a1}	= a first before-closure pressure-transient analysis adjusted variable, $m/Lt^{3/2}$, $psi^{1/2} \cdot cp^{1/2}$
c_{a2}	= a second before-closure pressure-transient analysis adjusted variable, $m^2/L^2t^{7/2}$, $psi^{3/2} \cdot cp^{1/2}$
d_a	= before-closure pressure-transient analysis adjusted variable, m/Lt^3, psi/hr
Δp_a	= adjusted pressure variable difference, m/Lt^2, psi
p_{ar}	= adjusted reservoir pressure variable, m/Lt^2, psi
p_{aw}	= wellbore adjusted pressure variable, m/Lt^2, psi
t_n	= time at timestep n, t, hr
t_{ne}	= time at the end of an injection, t, hr
$(x_a)_n$	= before-closure pressure-transient analysis adjusted variable, dimensionless
$(y_a)_n$	= before-closure pressure-transient analysis adjusted variable, dimensionless.

49. The method of claim 48 wherein the first and second before-closure pressure-transient analysis variables are defined as:

$$c_{a1} \equiv \sqrt{\frac{\bar{\mu}_g}{\phi \bar{c}_t}} \text{ ; and}$$

$$c_{a2} \equiv \frac{5.615}{24} S_f w_L \frac{\bar{B}_g}{(B_g)_{ne}} \sqrt{\frac{\bar{\mu}_g}{\phi \bar{c}_t}} \text{ ;}$$

wherein

ϕ	= porosity, dimensionless

B_g	=	gas formation volume factor, dimensionless, bbl/Mscf
$\bar{B}_g$	=	average gas formation volume factor, dimensionless, bbl/Mscf
S_f	=	fracture stiffness, m/L^2t^2, psi/ft
w_L	=	fracture lost width, L, ft.

50. The method of claim 49 wherein the transforming step is iterated with a value of n varying from $ne+1$ to a maximum value n_{max} and for each couple of coordinates $\{(y_a)_n, (x_a)_n\}$plot the graph $(y_a)_n$ versus $(x_a)_n$ to determine the intercept b_M,

wherein

ne	=	number of measurements that corresponds to the end of an injection
n_{max}	=	corresponds to the data point recorded at fracture closure or the last recorded data point before induced fracture closure.

51. The method of claim 50 wherein the fracture-face R_0 is determined by:

$$R_0 = \frac{5.615}{141.2\pi(24)} r_p S_f t_{ne} b_M$$

52. The method of claim 45 wherein the injection fluid is a liquid, a gas or a combination thereof.

53. The method of claim 52 wherein the injection fluid contains desirable additives for compatibility with the subterranean formation.

54. The method of claim 45 wherein the reservoir fluid is a liquid, a gas or a combination thereof.

55. A method of estimating fracture-face resistance R_0 of porous rocks of a subterranean formation containing a compressible reservoir fluid comprising the steps of:

(a) injecting an injection fluid into the subterranean formation at an injection pressure exceeding the subterranean formation fracture pressure;

(b) shutting in a zone of the subterranean formation;

(c) gathering pressure measurement data over time from the subterranean formation during shut-in;

(d) transforming the pressure measurement data into corresponding adjusted pseudopressure data and time into adjusted pseudotime data to minimize error associated with pressure-dependent reservoir fluid properties; and

(e) determining the fracture-face resistance R_0 of the subterranean formation from the adjusted pseudopressure and adjusted pseudotime data.

56. The method of claim 55 wherein a plot of the adjusted pseudopressure data over adjusted pseudotime data is a straight line with an intercept b_M a function of fracture-face resistance R_0.

57. The method of claim 56 wherein the adjusted pseudotime and adjusted pseudopressure data used in the transforming step are respectively determined by:

$$(t_a)_n = (\mu_g c_t)_0 \int_0^{(\Delta t)_n} \frac{d\Delta t}{(\mu_g c_t)_w} ; \text{ and}$$

$$(p_a)_n = \frac{\bar{\mu}_g \bar{c}_t}{\bar{p}} \int_0^{(p_w)_n} \frac{p dp}{\mu_g c_t} , \text{ wherein}$$

$\bar{\mu}$	= average viscosity, m/Lt, cp
μ_g	= gas viscosity, m/Lt, cp
p	= pressure, m/Lt^2, psi
$\bar{p}$	= average pressure, m/Lt^2, psi
p_a	= adjusted pseudopressure variable, m/Lt^2, psi
p_w	= wellbore pressure, m/Lt^2, psi
$p_{L_f D}$	= dimensionless pressure in a hydraulically fractured well, dimensionless
c_t	= total compressibility, Lt^2/m, psi^{-1}
$\bar{c}_t$	= average total compressibility, Lt^2/m, psi^{-1}.

58. The method of claim 57 wherein the straight line is defined by the equation:

$(y_{ap})_n = b_M + m_M (x_{ap})_n$, where

$$(y_{ap})_n \equiv \frac{(p_a)_n - p_{ar}}{(d_{ap})_n \sqrt{t_n} \sqrt{t_{ne}}},$$

$$(d_{ap})_j \equiv \frac{\bar{c}_t}{(c_t)_j}\left[\frac{[p_a(p)]_{j-1} - [p_a(p)]_j}{(t_a)_j - (t_a)_{j-1}}\right], \text{ and}$$

$$(x_{ap})_n \equiv \left[\begin{array}{l} c_{ap1}\left[\begin{array}{l} \dfrac{(d_{ap})_{ne+2}}{(d_{ap})_n}\left[\dfrac{(t_a)_n - (t_a)_{ne+1}}{t_n t_{ne}}\right]^{1/2} \\ + \displaystyle\sum_{j=ne+3}^{n} \dfrac{[(d_{ap})_j - (d_{ap})_{j-1}]}{(d_{ap})_n}\left(\dfrac{(t_a)_n - (t_a)_{j-1}}{t_n t_{ne}}\right)^{1/2} \end{array}\right] \\ + \dfrac{c_{ap2}(t_a)_n^{1/2}}{(d_{ap})_n t_n^{1/2} t_{ne}^{3/2}}\left[1 - \left(1 - \dfrac{(t_a)_{ne+1}}{(t_a)_n}\right)^{1/2}\right] \end{array}\right]$$

wherein

$c_{ap1} = c_{a1}$	= a first before-closure pressure-transient analysis adjusted variable, $m/Lt^{3/2}$, $psi^{1/2} \cdot cp^{1/2}$
$c_{ap2} = c_{a2}$	= a second before-closure pressure-transient analysis adjusted variable, $m^2/L^2t^{7/2}$, $psi^{3/2} \cdot cp^{1/2}$
d_{ap}	= before-closure pressure-transient analysis adjusted variable, m/Lt^3, psi/hr, with adjusted pseudotime variable
Δp_a	= adjusted pressure variable difference, m/Lt^2, psi
p_{ar}	= adjusted reservoir pressure variable, m/Lt^2, psi
p_{aw}	= wellbore adjusted pressure variable, m/Lt^2, psi
t_n	= time at timestep n, t, hr
t_{ne}	= time at the end of an injection, t, hr
$(t_a)_n$	= adjusted time at timestep n, t, hr
$(x_{ap})_n$	= before-closure pressure-transient analysis adjusted variable, dimensionless
$(y_{ap})_n$	= before-closure pressure-transient analysis adjusted variable, dimensionless.

59. The method of claim 58 wherein the first and second before-closure pressure-transient analysis variables are defined as:

$$c_{a1} \equiv \sqrt{\frac{\bar{\mu}_g}{\phi \bar{c}_t}}\text{ ; and}$$

$$c_{a2} \equiv \frac{5.615}{24} S_f w_L \frac{\bar{B}_g}{(B_g)_{ne}} \sqrt{\frac{\bar{\mu}_g}{\phi \bar{c}_t}};$$

wherein

ϕ	= porosity, dimensionless
B_g	= gas formation volume factor, dimensionless, bbl/Mscf
$\bar{B}_g$	= average gas formation volume factor, dimensionless, bbl/Mscf
S_f	= fracture stiffness, m/L^{2}t^2, psi/ft
w_L	= fracture lost width, L, ft.

60. The method of claim 59 wherein the transforming step is iterated with a value of n varying from $ne+1$ to a maximum value n_{max} and for each couple of coordinates $\{(y_{ap})_n, (x_{ap})_n\}$ plot the graph $(y_{ap})_n$ versus $(x_{ap})_n$ to determine the intercept b_M,
wherein

ne	= number of measurements that corresponds to the end of an injection
n_{max}	= corresponds to the data point recorded at fracture closure or the last recorded data point before induced fracture closure.

61. The method of claim 60 wherein the fracture-face R_0 is determined by:

$$R_0 = \frac{5.615}{141.2\pi(24)} r_p S_f t_{ne} b_M .$$

62. The method of claim 55 wherein the injection fluid is a liquid, a gas or a combination thereof.

63. The method of claim 62 wherein the injection fluid contains desirable additives for compatibility with the subterranean formation.

64. The method of claim 55 wherein the reservoir fluid is a liquid, a gas or a combination thereof.

65. A system for estimating physical parameters of porous rocks of a subterranean formation containing a compressible reservoir fluid comprising:

(a) a pump for injecting an injection fluid into the subterranean formation at an injection pressure exceeding the subterranean formation fracture pressure;

(b) means for gathering pressure measurement data from the subterranean formation during a shut-in period;

(c) means for transforming the pressure measurement data into adjusted pseudopressure data to minimize error associated with pressure-dependent reservoir fluid properties; and

(d) means for determining the physical parameters of the subterranean formation from the adjusted pseudopressure data.

66. The system of claim 65 wherein the determining means comprises graphics means for plotting a graph of the adjusted pseudopressure data over time, the graph being a straight line with a slope m_M and an intercept b_M wherein m_M is a function of permeability k and b_M is a function of fracture-face resistance R_0.

67. The system of claim 66 wherein the adjusted pseudopressure data is defined by the following equation:

$(p_a)_n = \frac{\bar{\mu}_g \bar{c}_t}{\bar{p}} \int_0^{(p_w)_n} \frac{p dp}{\mu_g c_t}$, wherein

$\bar{\mu}$	= average viscosity, m/Lt, cp
μ_g	= gas viscosity, m/Lt, cp
p	= pressure, m/Lt^2, psi
$\bar{p}$	= average pressure, m/Lt^2, psi
p_a	= adjusted pseudopressure variable, m/Lt^2, psi
p_w	= wellbore pressure, m/Lt^2, psi
p_{L_fD}	= dimensionless pressure in a hydraulically fractured well, dimensionless
c_t	= total compressibility, Lt^2/m, psi^{-1}
$\bar{c}_t$	= average total compressibility, Lt^2/m, psi^{-1}.

68. The system of claim 67 wherein the straight line is defined by the equation:

$(y_a)_n = m_M (x_a)_n + b_M$, where

$$(y_a)_n \equiv \frac{(p_a)_n - p_{ar}}{(d_a)_n \sqrt{t_n}\sqrt{t_{ne}}},$$

$$(d_a)_j \equiv \frac{(\mu_g)_j}{\bar{\mu}_g}\left[\frac{[p_a(p)]_{j-1} - [p_a(p)]_j}{t_j - t_{j-1}}\right], \text{ and}$$

$$(x_a)_n \equiv \left[\begin{array}{l} c_{a1}\left[\begin{array}{l} \frac{(d_a)_{ne+2}}{(d_a)_n}\left(\frac{t_n - t_{ne+1}}{t_n t_{ne}}\right)^{1/2} \\ + \sum\limits_{j=ne+3}^{n} \frac{[(d_a)_j - (d_a)_{j-1}]}{(d_a)_n}\left(\frac{t_n - t_{j-1}}{t_n t_{ne}}\right)^{1/2} \end{array}\right] \\ + \frac{c_{a2}}{(d_a)_n t_{ne}^{3/2}}\left[1 - \left(1 - \frac{t_{ne+1}}{t_n}\right)^{1/2}\right] \end{array}\right]$$

wherein

c_{a1}	= a first before-closure pressure-transient analysis adjusted variable, $m/Lt^{3/2}$, $psi^{1/2}\cdot cp^{1/2}$
c_{a2}	= a second before-closure pressure-transient analysis adjusted variable, $m^2/L^2t^{7/2}$, $psi^{3/2}\cdot cp^{1/2}$
d_a	= before-closure pressure-transient analysis adjusted variable, m/Lt^3, psi/hr
Δp_a	= adjusted pressure variable difference, m/Lt^2, psi
p_{ar}	= adjusted reservoir pressure variable, m/Lt^2, psi
p_{aw}	= wellbore adjusted pressure variable, m/Lt^2, psi
t_n	= time at timestep n, t, hr
t_{ne}	= time at the end of an injection, t, hr
$(x_a)_n$	= before-closure pressure-transient analysis adjusted variable, dimensionless
$(y_a)_n$	= before-closure pressure-transient analysis adjusted variable, dimensionless.

69. The system of claim 68 wherein the first and second before-closure pressure-transient analysis variables are defined as by the equations:

$$c_{a1} \equiv \sqrt{\frac{\bar{\mu}_g}{\phi \bar{c}_t}} \text{ ; and}$$

$$c_{a2} \equiv \frac{5.615}{24} S_f w_L \frac{\bar{B}_g}{(B_g)_{ne}} \sqrt{\frac{\bar{\mu}_g}{\phi \bar{c}_t}};$$

wherein

ϕ	= porosity, dimensionless

B_g	=	gas formation volume factor, dimensionless, bbl/Mscf
$\bar{B}_g$	=	average gas formation volume factor, dimensionless, bbl/Mscf
S_f	=	fracture stiffness, m/L^{2}t^2, psi/ft
w_L	=	fracture lost width, L, ft.

70. The system of claim 69 wherein the transforming means iterates the transformation of each adjusted pseudodata with a value of n varying from ne+1 to a maximum value n_{max}, and wherein the graphics means plots the graph $(y_a)_n$ versus $(x_a)_n$ to determine the slope m_M and the intercept b_M,

wherein

ne	=	number of measurements that corresponds to the end of an injection
n_{max}	=	corresponds to the data point recorded at fracture closure or the last recorded data point before induced fracture closure.

71. The system of claim 70 wherein the permeability k and the fracture-face R_0 are determined by the following equations:

$$k = \left[\frac{(141.2)(2)(0.02878)(24)}{5.615} \frac{1}{r_p S_f m_M} \right]^2 \text{; and}$$

$$R_0 = \frac{5.615}{141.2\pi(24)} r_p S_f t_{ne} b_M \,.$$

72. The system of claim 70 wherein the permeability k and the fracture-face R_0 are determined by the following equations:

$$\omega k = \left[\frac{(141.2)(2)(0.02878)(24)}{5.615} \frac{1}{r_p S_f m_M} \right]^2 \text{; and}$$

$$R_0 = \frac{5.615}{141.2\pi(24)} r_p S_f t_{ne} b_M \,;$$

wherein

ω	=	natural fracture storativity ratio, dimensionless.

73. The system of claim 65 wherein the injection fluid a liquid, a gas or a combination thereof.

74. The system of claim 73 wherein the injection fluid contains desirable additives for compatibility with the subterranean formation.

75. The system of claim 65 wherein the reservoir fluid is a liquid, a gas or a combination thereof.

76. A system of estimating physical parameters of porous rocks of a subterranean formation containing a compressible reservoir fluid comprising:

(a) a pump for injecting an injection fluid into the subterranean formation at an injection pressure exceeding the subterranean formation fracture pressure;

(b) means for gathering pressure measurement data from the subterranean formation during a shut-in period;

(c) means for transforming the pressure measurement data into adjusted pseudopressure data and time into adjusted pseudotime data to minimize error associated with pressure-dependent reservoir fluid properties; and

(d) means for detecting characteristics of the evolution in the adjusted pseudopressure data over adjusted pseudotime data to determine the physical parameters of the subterranean formation.

77. The system of claim 76 wherein the detecting means comprises graphics means for plotting the evolution of the adjusted pseudopressure data over adjusted pseudotime data, the evolution being a straight line with a slope m_M a function of permeability k and an intercept b_M a function of fracture-face resistance R_0.

78. The system of claim 77 wherein adjusted pseudotime and adjusted pseudopressure data are respectively determined by the equations:

$$(t_a)_n = (\mu_g c_t)_0 \int_0^{(\Delta t)_n} \frac{d\Delta t}{(\mu_g c_t)_w}; \text{ and}$$

$$(p_a)_n = \frac{\bar{\mu}_g \bar{c}_t}{\bar{p}} \int_0^{(p_w)_n} \frac{p dp}{\mu_g c_t}, \text{ wherein}$$

$\bar{\mu}$	=	average viscosity, m/Lt, cp
μ_g	=	gas viscosity, m/Lt, cp
p	=	pressure, m/Lt^2, psi
$\bar{p}$	=	average pressure, m/Lt^2, psi
p_a	=	adjusted pseudopressure variable, m/Lt^2, psi
p_w	=	wellbore pressure, m/Lt^2, psi
$p_{L_f D}$	=	dimensionless pressure in a hydraulically fractured well, dimensionless
c_t	=	total compressibility, Lt^2/m, psi^{-1}

$\bar{c}_t$ = average total compressibility, Lt^2/m, psi^{-1}.

79. The system of claim 78 wherein the straight line is defined by the equation:

$(y_{ap})_n = b_M + m_M (x_{ap})_n$, where

$$(y_{ap})_n \equiv \frac{(p_a)_n - p_{ar}}{(d_{ap})_n \sqrt{t_n}\sqrt{t_{ne}}},$$

$$(d_{ap})_j \equiv \frac{\bar{c}_t}{(c_t)_j}\left[\frac{[p_a(p)]_{j-1} - [p_a(p)]_j}{(t_a)_j - (t_a)_{j-1}}\right], \text{ and}$$

$$(x_{ap})_n \equiv \left[\begin{array}{l} c_{ap1}\left[\begin{array}{l}\dfrac{(d_{ap})_{ne+2}}{(d_{ap})_n}\left[\dfrac{(t_a)_n - (t_a)_{ne+1}}{t_n t_{ne}}\right]^{1/2} \\ + \displaystyle\sum_{j=ne+3}^{n} \dfrac{[(d_{ap})_j - (d_{ap})_{j-1}]}{(d_{ap})_n}\left(\dfrac{(t_a)_n - (t_a)_{j-1}}{t_n t_{ne}}\right)^{1/2}\end{array}\right] \\ + \dfrac{c_{ap2}(t_a)_n^{1/2}}{(d_{ap})_n t_n^{1/2} t_{ne}^{3/2}}\left[1 - \left(1 - \dfrac{(t_a)_{ne+1}}{(t_a)_n}\right)^{1/2}\right] \end{array}\right],$$

wherein

$c_{ap1}=c_{a1}$ = a first before-closure pressure-transient analysis adjusted variable, $m/Lt^{3/2}$, $psi^{1/2}\cdot cp^{1/2}$

$c_{ap2}=c_{a2}$ = a second before-closure pressure-transient analysis adjusted variable, $m^2/L^2t^{7/2}$, $psi^{3/2}\cdot cp^{1/2}$

d_{ap} = before-closure pressure-transient analysis adjusted variable, m/Lt^3, psi/hr, with adjusted pseudotime variable

Δp_a = adjusted pressure variable difference, m/Lt^2, psi

p_{ar} = adjusted reservoir pressure variable, m/Lt^2, psi

p_{aw} = wellbore adjusted pressure variable, m/Lt^2, psi

t_n = time at timestep n, t, hr

t_{ne} = time at the end of an injection, t, hr

$(t_a)_n$ = adjusted time at timestep n, t, hr

$(x_{ap})_n$ = before-closure pressure-transient analysis adjusted variable, dimensionless

$(y_{ap})_n$ = before-closure pressure-transient analysis adjusted variable, dimensionless.

80. The system of claim 79 wherein the first and second before-closure pressure-transient analysis variables are defined as:

$$c_{a1} \equiv \sqrt{\frac{\bar{\mu}_g}{\phi \bar{c}_t}}$$; and

$$c_{a2} \equiv \frac{5.615}{24} S_f w_L \frac{\bar{B}_g}{(B_g)_{ne}} \sqrt{\frac{\bar{\mu}_g}{\phi \bar{c}_t}}$$;

wherein

ϕ	= porosity, dimensionless
B_g	= gas formation volume factor, dimensionless, bbl/Mscf
$\bar{B}_g$	= average gas formation volume factor, dimensionless, bbl/Mscf
S_f	= fracture stiffness, m/L^{2}t^2, psi/ft
w_L	= fracture lost width, L, ft.

81. The system of claim 80 wherein the transforming means iterates the transformation of each adjusted pseudodata with a value of n varying from ne+1 to a maximum value n_{max}, and wherein the graphics means plots the graph $(y_a)_n$ versus $(x_a)_n$ to determine the slope m_M and the intercept b_M,

wherein

ne	= number of measurements that corresponds to the end of an injection
n_{max}	= corresponds to the data point recorded at fracture closure or the last recorded data point before induced fracture closure.

82. The system of claim 80 wherein the permeability k and the fracture-face R_0 are determined by the equations:

$$k = \left[\frac{(141.2)(2)(0.02878)(24)}{5.615} \frac{1}{r_p S_f m_M} \right]^2$$; and

$$R_0 = \frac{5.615}{141.2\pi(24)} r_p S_f t_{ne} b_M .$$

83. The system of claim 80 wherein the permeability k and the fracture-face R_0 are determined by the equations:

$$\omega k = \left[\frac{(141.2)(2)(0.02878)(24)}{5.615} \frac{1}{r_p S_f m_M} \right]^2$$;

$$R_0 = \frac{5.615}{141.2\pi(24)} r_p S_f t_{ne} b_M \ ;$$

wherein

ω = natural fracture storativity ratio, dimensionless.

84. The system of claim 76 wherein the injection fluid is of a liquid, a gas or a combination thereof.

85. The system of claim 84 wherein the injection fluid contains desirable additives for compatibility with the subterranean formation.

86. The system of claim 76 wherein the reservoir fluid is a liquid, a gas or a combination thereof.